ISSUE BRIEF 11

THE ELECTRICITY SECTOR AND CLIMATE POLICY

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SUMMARY

The electricity sector is the most prominent target for climate policy because it is the largest single source of carbon dioxide (CO_2) emissions and of potential CO_2 emissions reductions in the United States. Moreover, because electric power generators are among the largest point sources of important air pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NOx), and mercury, the industry has been extensively regulated in the past. An economy-wide climate policy will achieve emissions reductions at least cost, but advocates of an electricity-focused policy believe it could serve as a bridge to—or component of—a broader policy. State governments have moved ahead of the federal government in adopting various climate-related policies that affect the electricity sector, some of which may complement and some of which may conflict with a future federal policy.

- One of the major challenges of designing a federal cap-and-trade system for greenhouse gas (GHG) emissions is addressing the heterogeneous way such a system would affect electricity producers and consumers across the country. This heterogeneity arises from regional differences in the way electricity is regulated and in the fuels used for electricity generation.

- In states with market-determined prices, free allowance allocation to emitting companies can deliver net gains to companies and provide little relief to customers.

- In states under cost-of-service regulation, free allowance allocation is likely to produce essentially the opposite result: providing benefits to customers with little net financial impact on companies.

- In general, the electricity industry should be able to pass through a large fraction of the cost of emissions reductions by charging consumers higher prices for electricity. At the sector level, only a small share of allowances created by a cap-and-trade policy would need to be distributed for free to incumbent generators to preserve the market value of the industry's portfolio of existing assets—this point being most relevant for market-based generators. At the level of an individual firm, however, the effects of a mandatory climate policy on the market value of existing assets can be more severe.

- Technology standards, performance standards, and programs to increase energy efficiency are thought to be less cost-effective, from a broad economic perspective, than emissions caps (or taxes) as a means of reducing CO_2 emissions. Nonetheless, these other policies may be justified as ways to address a market-failure. If CO_2 emissions are capped, a key effect of these other policies would be to reduce the demand for, and therefore the price of, CO_2 emissions allowances; but they would not produce additional emissions reductions below the cap.

Introduction

The U.S. electricity generation sector is responsible for roughly 40 percent of all CO_2 emissions in the United States and 9 percent of energy-related CO_2 emissions worldwide. Thus it is a major target of domestic climate policy proposals.[1] Proposals to cap emissions of CO_2 from electricity generators, generally as a part of a larger package to reduce emissions of multiple pollutants, have emerged in each of the past several sessions of Congress. The electricity sector is also covered under numerous economy-wide GHG cap-and-trade proposals introduced in the 110th Congress. While none of the federal legislative proposals has been enacted, several states have proceeded with developing their own regulatory programs. A group of governors of ten Northeast states extending from Maryland to Maine, for example, has signed on to the Regional Greenhouse Gas Initiative (RGGI) with the aim of imposing the world's second mandatory cap on CO_2 emissions (after the European Union's Emission Trading Scheme) beginning in 2009. The RGGI program seeks to reduce electric-sector emissions from participating states by approximately 35 percent below business-as-usual levels by 2020. California has adopted a more stringent target: the state aims to return its economy-wide emissions to 1990 levels by 2020. Moreover, California law specifies that the emissions-reduction target includes all emissions associated with electricity generation to serve California customers, including emissions from facilities located outside the state.[2] A group of western states, including Washington, Oregon, Arizona, New Mexico, Utah, and two Canadian provinces, have since joined California in an effort to develop a regional policy. Many other states have initiatives underway, including New Jersey and Florida, which recently proposed policies that address GHG emissions.

While cap-and-trade policies, either economy-wide or sector-specific, have received the most attention in the domestic climate policy debate, a number of other potential policies have been proposed to reduce CO_2 emissions from the electricity sector. Chief among these alternatives would be a CO_2 emissions tax. A tax would have the advantage of being easier to administer and it would avoid the question of whether and how to allocate allowances to the private sector under a cap-and-trade program. Instead, policymakers would need to decide how to use tax revenues; but this decision is more explicit and transparent than free allocation of emission allowances. One of the reasons that regulated sources may prefer an emissions-trading program to a tax is that under past cap-and-trade systems, the great majority of emission allowances have been given away for free to companies, usually on the basis of a measure (such as heat input) that relates to past emissions. In the domestic climate policy debate, how to initially distribute emissions allowances remains an open question. Policymakers are struggling to define principles for the allocation of allowances and are seriously entertaining proposals that would auction (rather than give away for free) some or all of these valuable assets. At the same time, policymakers are considering a variety of additional options to address electric-sector GHG emissions, including renewable portfolio standards (RPS) and policies to encourage demand-side energy efficiency and conservation. GHG performance standards for new electricity generators could well emerge as another policy option; this approach would continue 35 years of regulatory precedent. The purpose of this issue brief is to summarize alternative approaches to reducing CO_2 emissions from electricity generation.

Brief Background on the Electricity Sector

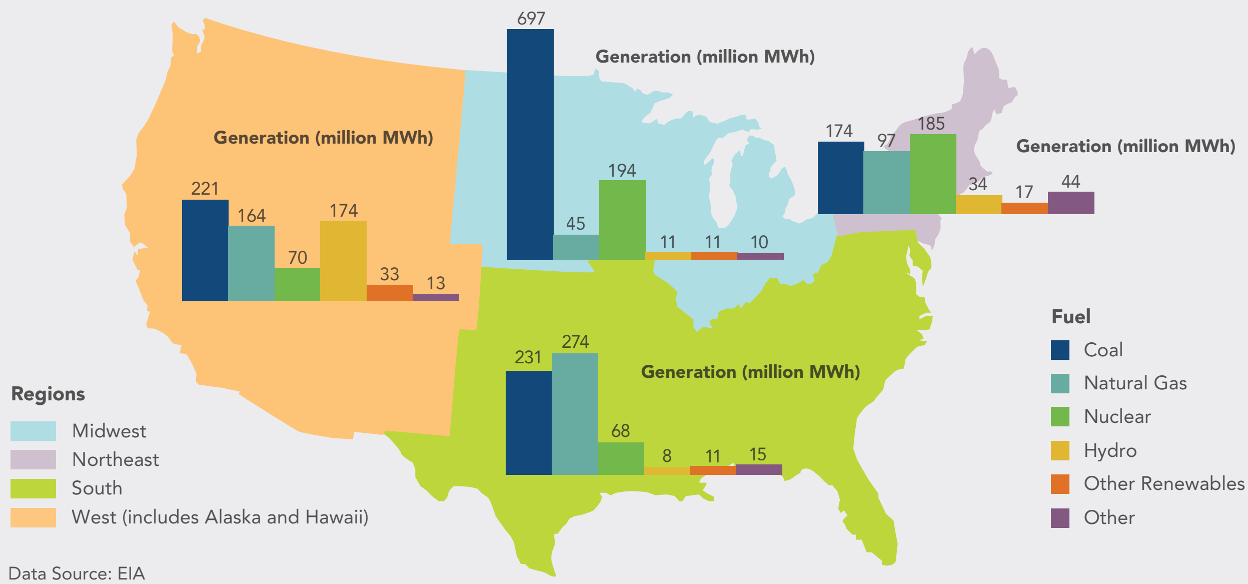
Two features of the electricity industry are important to understand when considering how to regulate CO_2 emissions from this sector. The first concerns the mix of fuels used to generate electricity. Just over half (51 percent) of the electricity generated in the United States is produced using coal, which has an average CO_2 emissions rate of roughly 1 ton per megawatt-hour (MWh). Natural gas, the second most important fossil fuel used to generate electricity, accounted for approximately 16 percent of electricity generation nationally in 2004; average CO_2 emissions per MWh generated using natural gas are roughly half the emissions associated with coal. Nuclear power and renewable energy, including hydropower, are important non-emitting sources of generation; they currently account for about 21 percent and 9 percent of the nation's electricity mix, respectively. Figure 1 shows the mix of fuels used to generate electricity by region.

Table 1 shows changes in technology and fuel use in the electricity sector that could result from carbon regulation. The table shows the generation mix for 2004 and the projected mix for 2030 based on forecasts developed by the Energy Information Administration (EIA) under a business-as-usual scenario with no climate policy. The Electric Power Research Institute (EPRI) has studied the technical potential of advanced

1 Emissions of CO_2 from the electricity sector account for 33 percent of total GHG emissions in the United States.

2 California's in-state generation mix has relatively low emissions. The same is not true of the generation mix associated with power imported to the state. In fact, imported power accounts for roughly 20 percent of California's electricity consumption, but about half of overall CO_2 emissions from electricity use in the state. Legal restrictions under the Commerce Clause of the Constitution and the Federal Power Act constrain the state's ability to limit emissions from out-of-state sources of electricity, but efforts to design policies that would address this issue are underway.

Figure 1 Electricity Generation by Fuel in 2005



Data Source: EIA

power-generation technologies that could be deployed in response to a climate policy, setting aside cost considerations. EPRI contemplates a dramatic increase in nuclear and natural gas, and a decline in new conventional coal plants, with the new coal generation that does get built shifting toward systems that make use of carbon capture and storage technology. The EIA has analyzed a price-based policy that would impose a cost of \$35 per ton CO_2 (in 2004 dollars) by 2030. EIA's projections for nuclear power are similar to those in the EPRI study, but the EIA results show much smaller growth in natural gas generation. A smaller increase in natural-gas use is made up by additional growth in non-hydro renewables. Compared to EPRI, EIA also finds a much larger decline in coal generation under GHG constraints and a bigger decline in total electricity generation. Perhaps the distinction to note between these two studies is that EIA presents a more conventional view of technology options but offers an economic view of how investment decisions are made. One important issue that neither study is able to account for is the difficulty of siting new facilities. This deployment hurdle is especially daunting for nuclear power and for new transmission capability, which may be necessary to bring renewables to market. In addition, there is no experience with siting infrastructure for large-scale carbon capture and storage.

The mix of fuels used to generate electricity varies substantially across the country with coal playing a big role in the Midwest, Southeast, and Mountain states and natural gas being more prominent in the Gulf states, New England, and the Pacific states. This variation is important because coal-dependent states would be more affected by CO_2 restrictions than other states. Renewable resources are also concentrated more heavily in some parts of the country than in others, as indicated in Figure 2. This figure shows how much of different kinds of non-hydro renewable generation are projected to come from different regions under an EIA model simulation of a policy that requires renewable generators to supply 15 percent of the electricity sold by large utilities in 2020. Figure 2 suggests that a national policy designed to promote increased use of renewable resources will have differential impacts across regions of the country. Of particular interest is the effect in the Southeast, where EIA finds that biomass generation, both from dedicated biomass plants and from co-firing with biomass at existing coal plants, grows substantially. Some doubt this finding because it is not clear that available

Table 1 Technologies for Electricity Generation in 2030.

	Generation (billion kWh)		Change in Generation from EIA Reference Case (billion kWh)	
Technology	Data	EIA Reference Case	EPRI Advanced Technology Targets*	EIA Cap-Trade Case (CT-3)**
Nuclear	789	871	506	547
Renewables***	323	504	123	687
Total Coal	1,954	3,205	-310	-1,439
Coal w/ CCS			789	****
Natural Gas	619	822	-352	48
Petroleum	115	101		-74
TOTAL	3,800	5,503	-102	-231

* Amounts in this column do not sum to the total because of additional data not presented here.
**Allowance price in Cap-Trade Case (2004 dollars): $22.09/ton CO_2 in 2010 and $35.34 in 2030.
***Includes hydro.
****Except for plants currently under construction the only coal plants built have CCS technology.

2004 Generation Data: *Total Electric Power Industry data from Table EIA-906: "Net Generation by State by Type of Producer by Energy Source." Available at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.*

EIA Reference Case and Cap-Trade Case: *Energy Information Agency, "Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals," (Table ES 2b) March 2006. Available at: http://tonto.eia.doe.gov/FTPROOT/service/sroiaf(2006)01.pdf.*

EPRI Advanced Technology Target: *S. Specker, "Electricity Technology in a Carbon Constrained Future," (page 15) Electric Power Research Institute. February 2007. Available at: http://mydocs.epri.com/docs/CorporateDocuments/Newsroom/EPRIUSElectSectorCO$_2$Impacts_021507.pdf.*

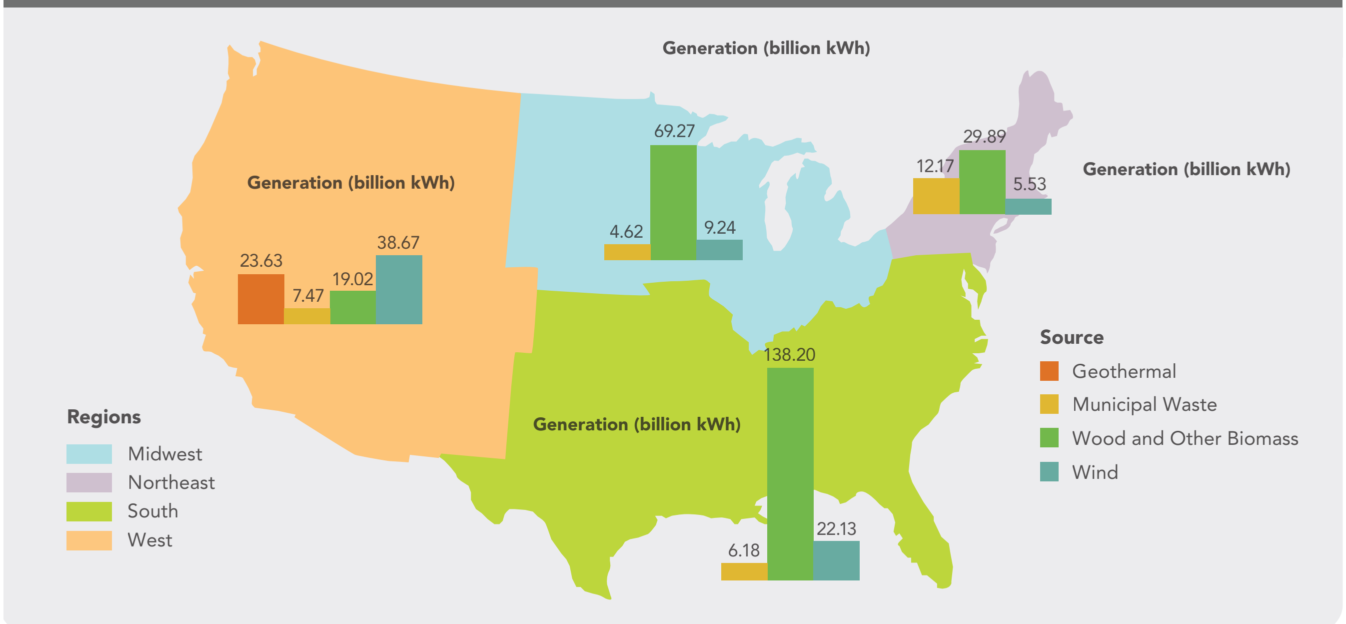
biomass resources in the Southeast are as abundant or low-cost as the EIA analysis assumes. Nationally, the EIA modeling results show a ten-fold increase in biomass generation from 2005 levels and a nearly three-fold increase over the levels that would be expected absent the 15 percent renewable energy requirement.

Regional differences in the effects of a federal climate policy are also driven by variations in the structure and regulation of the electricity sector. The traditional industry structure of vertically integrated utilities supplying retail customers with the bulk of their electricity needs at regulated prices is still the dominant model in much of the country, including in the South and in the Mountain and Plains states. States in other parts of the country have opened their electricity sector to more competition in generation, with generally limited entry by competitive retail providers, and have seen divestitures of generation assets to independent power producers. In these regions, the prices paid by electricity consumers reflect the marginal costs of generation as determined in wholesale markets rather than regulated rates set to guarantee cost recovery for service providers. This difference has important implications for how customers experience the costs of climate policies, particularly under different methodologies for allocating emissions allowances in the context of a cap-and-trade policy. We return to this issue in a later section.

Economy-Wide Versus Electricity-Specific Programs

The question of whether a policy should be economywide or focused on the electricity sector is a complex one. As discussed at length in other issue briefs (notably Issue Briefs #4 and #5) a broad-based policy that includes all GHG sources

Figure 2 Predicted Renewables Generation by Type in 2020 under a 15% Renewable Portfolio Standard



This map displays an approximate representation of the regional renewable generation results from the "Impacts of a 15-Percent Renewable Portfolio Standard" by the U.S. Energy Information Administration, Report # SR-OIAF/2007-03, June 2007.

and sinks will achieve the most emissions reductions at the lowest overall cost to society. In particular, a singular focus on the electricity sector will tend to direct energy consumers away from electricity and toward the direct use of primary fuels such as natural gas or oil. This would shift emissions to un-covered sources (creating emissions "leakage") and would undermine the environmental objectives of the program. Sector-specific policies may have their own independent justifications and consequences, but such programs assuredly would not achieve emissions reductions in the most cost-effective manner because the cost of emissions reductions would vary across sectors. If a cap-and-trade approach is used, then applying it broadly—to as many sources and sectors as possible—would create rational price signals for all sorts of investment and consumption decisions throughout the economy.

As an initial step, a sector-specific policy could be consistent with the ideal of a broad-based approach if it creates a bridge to a more comprehensive program. EIA modeling analyses of various cap-and-trade programs suggest that roughly two-thirds to three-fourths of emissions reductions under a broad-based approach will come from the electricity sector, at least for the first couple decades of a flexible economy-wide CO_2 program. Thus there may be significant overlap between the nearer-term, relatively low-cost emissions reductions elicited by an electric-sector-only policy and an economy-wide policy. Starting with a sector-specific policy may also avoid some of the competitiveness concerns that tend to arise in connection with an economy-wide program, since the electricity sector at a national level is not subject to export substitution in the same way that other energy-intensive sectors (aluminum, for example) may be. That is, focusing on electricity in a domestic policy is unlikely to lead to an exodus of electricity producers. However, even a sector-specific policy is unlikely to comprehensively capture all GHG emissions from electricity generation, depending on how affected sources are defined. Some program designs, for example, might not cover off-grid or self-generation and may inadvertently create incentives for expanded self-generation (especially by large electricity users).

Regulatory Options in the Electricity Sector

Several options exist for regulating CO_2 emissions in the electricity sector. Some are mutually exclusive while others could be implemented in a complementary fashion. Reductions in electric-sector CO_2 emissions will be brought about by changes in demand and supply. The list of policy options reviewed in this issue brief is organized roughly in order of increasing prescriptiveness at the federal level; in addition, the policy options further down the list may imply a greater role for state agencies:

- Incentive-based GHG policies (cap-and-trade or emissions tax)
- Performance standards
- Technology standards and direct technology support
- Introducing environmental concerns into resource planning
- Policies to promote demand-side efficiency

Incentive-Based Approaches

Economists view incentive-based regulation—either a cap-and-trade program or emissions taxes—as the most efficient approach to reducing emissions. By imposing a cost on all emissions, both provide strong incentives for continuous innovation to develop lower-carbon technologies for electricity generation. Although there are differences between tradable permit systems and a tax, a cap-and-trade program can be modified to mimic some of the features of a tax and vice versa.[3] In particular, assuming banking is allowed in a trading program, both a trading approach and tax give firms flexibility in terms of the nature and timing of mitigation measures undertaken. For purposes of this discussion we focus on cap and trade, because this approach is featured in most current proposals.

To what extent a carbon pricing policy creates incentives for electricity consumers to reduce consumption depends in part on how electricity prices are determined and on how emissions allowances are distributed initially. Both issues are discussed at length below.

Performance Standards

Performance standards come in two flavors. We use the term 'technology standard' to refer to standards that do not provide any flexibility in the design or operation of a facility. By contrast, the term 'performance standard' is increasingly being used to describe a standard that must be met, in aggregate or on average, by a portfolio of facilities, perhaps with different technologies. In other words, such standards specify a maximum or, when trading is allowed, an average level of emissions that is not technology specific. Recent proposals have called for a clean energy portfolio standard to encourage a mix of new nuclear, renewable, and new fossil generation with carbon capture. Another example that has already been adopted by several states is the renewable portfolio standard (RPS), which requires a certain level of generation using non-hydro renewable energy resources (rather than non-emitting technologies more generally).[4] Portfolio standards typically require that a percentage of electricity generated or sold to customers must be provided using a listed set of technologies. Most proposals for a national-level portfolio standard would give electricity providers flexibility to determine what mix of listed technologies allows them to meet the standard most cost-effectively and would provide the added flexibility of trading. Trading allows utilities that face higher costs for renewable energy to purchase excess renewable- or clean-energy credits from other utilities or merchant generators that face lower costs to help meet their compliance obligation. More than 20 states have adopted RPS policies. Generally these policies make retail utilities responsible for compliance. In contrast to a national policy that would likely allow relatively unrestricted credit trading among utilities, trading under all but a handful of state policies is more constrained in the sense that it is generally limited to sources within a nearby geographic region. Several state programs also have specific targets or requirements for particular types of renewables, such as solar power, under the broader RPS.

Performance standards or portfolio requirements can be used to overcome deployment hurdles for renewable sources of energy.[5] As a technology deployment (rather than emissions reduction) policy, a national RPS would tend, in the short run, to have a fairly small effect on electricity prices in competitive wholesale power markets—at least as long as incumbent facilities continue to operate, which is likely to be quite a long time in the electricity sector. The near-term effect on electricity prices would likely be small because renewable energy credits that subsidize the operating cost of renewable generators are essentially funded by payments from the existing fleet

3 See Issue Brief #5.

4 Both types of proposals have been introduced in the 110th Congress. Senate Amendment 1538, for example, would establish a national clean energy portfolio standard, whereas Senate Amendment 1537 and similar legislation in the House of Representatives (H.R. 969) would establish a national renewable portfolio standard.

5 As noted previously, the application of portfolio standards or other forms of regulation to emissions sources that are also covered under a cap-and-trade program will not produce additional emissions reductions—such policies may affect the means used to achieve the cap or the distribution of emissions reductions across different sources and entities, but overall emissions will always rise to the level of the cap. Additional technology-oriented policies *can*, however, be expected to reduce the market price of allowances (by effectively creating a separate constraint on emissions that reduces demand for allowances), thus potentially also ameliorating the apparent price impacts of the policy (albeit not its overall cost to society). For further discussion of these issues and of the arguments for and against technology deployment policies more generally, see Issue Brief #10.

of fossil generators. Although these payments raise the variable cost of operation for fossil generators, the change in marginal generation cost is offset to some degree by the reduced utilization of high-cost fossil units that are displaced by the introduction of renewables. In the long run, however, the marginal cost of generation will be dominated by new investment and at that point the subsidy for renewables would be more apparent in electricity prices.

Wind would likely be the dominant new technology to enter the market in response to a national renewable energy mandate, particularly if the RPS target is relatively low. Wind energy has low variable costs—once a wind facility is built, the costs of operating that facility are relatively small since it uses a "fuel" that, when available, is essentially free. Thus, although wind is an intermittent resource, the marginal cost of using it to produce a MWh of electricity is likely to be smaller than the market value of the renewable energy credit it would generate under a mandatory RPS. To the extent that the subsidy effect of the credit more than compensates for variable operating costs at renewable energy plants, the immediate impact of the RPS policy on electricity prices would likely be small. Under somewhat higher national RPS targets, of course, other renewable technologies—notably biomass—would be expected to play a more important role. Nevertheless, variable operating costs for biomass generation, though they are typically higher than variable operating costs for wind, would likely still be significantly offset by the value of renewable energy credits. Thus, in competitive wholesale power markets, during specific times of day and in specific regions, an RPS policy may actually lead to a reduction in electricity price in the near term.

In competitive markets, existing fossil-fuel electricity generators (rather than end-use consumers) would be expected to bear the lion's share of the cost of a renewable or clean energy technology requirement in the form of lower profits. Also, by reducing electricity producers' demand for natural gas, an RPS policy actually can reduce the price of natural gas to households and businesses. An RPS policy may help to reduce the cost or improve the performance of future renewable power sources if the industry, through learning-by-doing as more renewables are brought on line, discovers cheaper ways to build and more efficient ways to operate renewable energy technologies.

As already noted, renewable energy policies do not target CO_2 emissions directly; thus they will not produce emissions reductions as cost-effectively as a cap-and-trade approach.

To what extent a carbon pricing policy creates incentives for electricity consumers to reduce consumption depends in part on how electricity prices are determined and on how emissions allowances are distributed initially.

Even in their most efficient forms—including, for example, program designs that allow for national-level trading—portfolio standards that target particular technologies are a more costly way to achieve emission reductions than approaches that address emissions directly through a cap-and-trade program or an emissions tax. Renewable energy mandates may induce the deployment of targeted generation technologies in an efficient manner, but the targeted technologies may not be the least-cost option for reducing emissions. Instead, the more compelling justification for such policies is likely to be grounded in the argument that they are needed to address market problems that would otherwise hinder the deployment of even cost-effective renewable energy resources. Furthermore, the fuel-use interaction is complex. Research has shown that at a national level, an RPS policy would tend to displace natural gas generation more than coal—thus existing high-emitting plants would probably not be displaced by renewables; instead, new gas plants would not be built.

Technology Standards and Direct Technology Support

Technology standards prescribe minimum emissions performance requirements for electricity generation technologies. Familiar examples include the new source performance standards that apply to all new generation facilities under the Clean Air Act. New source performance standards currently exist for SO_2 and NOx and generally require the installation of "best" available control technologies on new generators. Although known as performance standards because they are denominated by a performance metric (typically expressed in units of emissions per unit of heat input or, in some cases, emissions per unit of electricity output), in practice there is typically one identified (best) technology that can achieve the standard. In the climate context, an example of a technology standard would be to require that all new coal-fired power plants be equipped with the technology to capture and sequester CO_2.

Legislation recently adopted in California (Senate Bill 1368) creates a de facto technology standard by prohibiting the state's utilities from entering into long-term contracts with generators that emit more than 1,100 pounds of CO_2 per MWh of electricity output. Besides renewable or other zero-carbon technologies, the only conventional fossil-fuel technology now available that can meet this standard is a natural gas-fired combined-cycle gas turbine. Coal plants could not meet this standard using current technology; they would need to incorporate carbon capture systems. The technology for carbon capture is still in the development phase, however, and has not yet been deployed on a large-scale, commercial basis. It is unclear what effect the California standard will have in the near term because other western states have had the opportunity to shuffle resources such that power conforming to the standard could be sold into California while higher-emitting generation was dedicated to other parts of the region. However, research at the California Energy Commission indicates that the opportunity for sustained contract shuffling—after accounting for ownership and long-term contracts, along with oversight by California agencies—is limited.[6] In addition, accounts in the trade press suggest that the California standard has already altered the investment climate for new capacity outside the state by introducing the risk that uncontrolled coal facilities may not be able to serve the California market. If such standards become more widespread they will certainly spark more investment in developing the technologies and regulations necessary to make a carbon capture and sequestration commercially viable.

One difference between the performance (or portfolio) standards described above and more rigid technology standards is that the former typically target the characteristics of a mix of generation technologies while the latter target the characteristics of a specific generation technology. The rationale for technology standards is closely linked to the long expected life of new generating facilities, most of which are likely to operate for a half century or more. However, technology standards also raise the cost of building new facilities relative to the cost of continuing to operate existing facilities, thereby delaying equipment turnover and the efficiency improvements that would result from replacing old technology. Also, rules governing what constitutes "new equipment" when existing facilities are upgraded raise difficult administrative issues. Consequently, although taken for granted as a good idea by most environmental advocates, technology standards are among the regulatory approaches least favored by economists.

Finally, we note that, in practice, development and deployment policies directly targeting specific technologies can be used to fund or otherwise provide direct support for technologies that are expected to be relevant for generating electricity with low net GHG emissions. Such policies are discussed in more detail in Issue Briefs #9 and #10. The key trade-offs in developing technology policies revolve around the difficulty of identifying which technologies should receive direct support and at what stage of development. Other critical questions include how much support should be provided and in what form. Direct technology support has been an important component of U.S. energy policy in the past, and is likely to continue to be so in the future.

Introducing Environmental Concerns into Resource Planning

Investment in cleaner generating technologies is critical to reducing CO_2 emissions from the electricity sector. States have used several approaches to encourage such investments, in many cases by intervening in the generation planning process to require greater emphasis on renewable energy technologies or demand side management. Another approach that several states relied on in the past was to require that environmental costs be incorporated in integrated resource planning in a quantitative manner. A formal open resource planning process is often part of public utility commission oversight of the investment plans of regulated utilities; as part of that process, both supply-side generation options and demand-side energy-efficiency options may be considered. In the planning context, social costs may be included by giving weight to the environmental performance of various resources. Around the time the 1992 Energy Policy Act was passed, roughly 20 states included environmental costs in some manner in resource planning. In retrospect, many of those

6 Alvarado, A and Griffin K. (2007). Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports: Update to the May 2006 Staff Paper. Sacramento, CA: California Energy Commission.

states were the ones that moved to deregulate their electricity markets and sever the link between independently-owned generation and regulated load serving entities, thereby ending states' direct regulatory influence over investment planning. Nonetheless, the integrated resource planning process survives, especially in regions with cost-of-service regulation, although the extent to which environmental costs are explicitly included varies across states.

Demand-Side Policies

Another way to reduce emissions is to reduce demand for electricity by improving the efficiency of electric appliances and equipment. Separate from the climate debate, numerous policies and measures have been advanced at the federal and state levels to promote energy efficiency; common strategies have included appliance standards, utility demand-side management (DSM) programs, and building codes and standards.

The climate debate has renewed interest in demand-side policies at both the federal and state levels. Policymakers are looking for ways to expand and improve the performance of existing utility conservation and DSM programs and to promote these programs more broadly. Under traditional rate regulation, utility revenues and profits are tied to electricity sales at a set tariff. Because utilities earn more by selling more electricity they have little incentive to work to reduce customer demand. One way to address this incentive problem is known as revenue decoupling; as the term implies, it involves breaking the link between utility revenues and number of kilowatt hours sold. Instead, electricity prices are adjusted in a way that keeps overall revenues whole. Decoupling changes the incentives such that it is in the utility's interest to minimize costs per customer served, including—where cost-effective—by helping that customer reduce end-use demand. To make the utility whole, the kilowatt-hour price of delivered electricity may rise as increased efficiency investments lead to lower sales. From the perspective of an individual customer, a higher price will provide further incentives to reduce consumption; it may also, however, lead to some electricity users cross-subsidizing others, depending on how efficiency expenditures affect different classes of customers. Advocates of revenue decoupling claim that it removes disincentives for utility investment in customer-side efficiency improvements, but that by itself may be insufficient to provide positive incentives for expanded DSM programs. Consequently, some states are going a step further by allowing utility-company shareholders the opportunity to earn a return on capital investments in energy efficiency.

Some states, such as Texas, are experimenting with yet another policy option, known as an efficiency portfolio standard (EPS). Much like an RPS, an EPS requires utilities to use energy efficiency programs to meet a minimum percentage of projected demand for electricity services. Equivalently, utilities must acquire efficiency credits in proportion to generation, where credits are created by investing in energy efficiency programs. A few states, including Connecticut and Hawaii, have combined the RPS and EPS to create a minimum standard for efficiency and renewable generation. Both policies—EPS and RPS—have also been proposed at the federal level.

Implementing efficiency portfolio policies (and evaluating demand-side programs more generally) poses important challenges in terms of measuring and verifying the amount of energy saved by particular measures and investments. Engineering studies typically conclude that there are enormous opportunities to improve end-use efficiency at low cost. According to one study that involved three national laboratories, electricity demand reductions on the order of 24 percent are achievable nationwide.[7] However, a variety of institutional and market barriers stand in the way of capturing these savings. For instance, due to the diffuse nature of many energy-saving opportunities, identifying and implementing efficiency improvements is often an unrecognized or low priority for busy firms and households. Also, efficiency programs frequently have a variety of hidden administrative costs. In many cases, incentives are not aligned with responsibility for investment decisions and control over energy practices within business organizations, institutions, and buildings. Another factor that may diminish the cost-effectiveness of efficiency measures as a means to reduce GHG emissions is that reduced demand for electricity tends to back out investments in new generators, which themselves tend to be more efficient and have lower CO_2 emissions rates per kWh than older generators.

Allowance Allocation in the Electricity Sector

The presumptive design for federal legislation to curb U.S. GHG emissions at this time is a cap-and-trade program.

7 Interlaboratory Working Group (2000). Scenarios for a Clean Energy Future. Oak Ridge National Laboratory, Oak Ridge Tennessee; Lawrence Berkeley National Laboratory, Berkeley, California; and National Renewable Energy Laboratory, Golden, Colorado. The study identifies the "achievable energy savings potential," which is a subset of energy efficiency measures that have been identified as cost-effective on an engineering-cost basis and achievable based on past experience and the propensity of the electricity-consuming households and businesses to adopt such measures. Other studies find similar results—that is, estimated savings on the order of a 25 percent reduction in electricity use—for various regions of the country. See Nadel, S., Shipley, A., and Elliott, R.N (2004). The Technical, Economic and Achievable Potential for Energy Efficiency in the U.S.—A Meta-Analysis of Recent Studies. American Council for an Energy-Efficient Economy, Washington, DC.

Whatever means are adopted to achieve emissions reductions, the lion's share of costs of reducing electric-sector CO_2 emissions will be borne by electricity customers, and a smaller share will fall to firms and their owners. A cap-and-trade program provides an obvious way to cushion these cost impacts by creating a valuable asset—emissions allowances—that can be transferred back to customers and firms. Deciding how, exactly, to distribute allowance value to intended parties via allocation is not straightforward. Furthermore, providing free allowances as a means of compensating particular stakeholders tends to raise the cost of the overall policy dramatically compared to auctioning emissions allowances and using the proceeds in ways that boost overall economic efficiency (e.g. by reducing taxes on income or investment).[8] Thus, some of the most vexing issues associated with designing a cap-and-trade program involve the initial distribution of emissions allowances, including whether allowances should be directly allocated or auctioned.

The question of how to allocate CO_2 emissions allowances within the electricity sector is complicated by important differences in the way states regulate electricity markets. At present, the country is divided into essentially two regulatory models: in some states, markets determine the generation component of electricity price while in other states electricity prices are set by cost-of-service regulation. In price-regulated markets, generators most likely will not be allowed to pass through the cost of GHG emissions under a cap-and-trade program if they have been given free allowances. This is because free allowances have zero original cost and original cost is what regulators add to a firm's total cost to determine electricity rates. Even though utilities will consider the opportunity cost of using free allowances in the operation of generation technology, this opportunity value will not be reflected in retail prices in regulated regions. In competitive regions, however, the opportunity cost of using allowances will be reflected in retail prices—that is, even if generators receive a free allocation initially they will pass allowance costs through to customers to the extent they can. This difference means that if allowances are distributed for free to generators based on a fixed historic measure, the impact of a mandatory CO_2 policy on electricity prices will be much greater in states where markets set electricity prices than in states where regulators set prices based on cost. Depending on the stringency of the climate policy, this difference could result in major disparities in the electricity price increases that occur across different states and regions under a common federal cap-and-trade program for GHG emissions.

One way to address this disparity would be to auction emissions allowances to the highest bidder. Regulated generators would then pay a price for each allowance they acquire; this cost would become part of utilities' total cost and thus would be folded into retail rates. In the long run, generators in regulated regions could be expected to recover their emissions costs; in the short run, however, regulators may be reluctant to let electricity prices rise too far—as a result, there is always some possibility that they may disallow some portion of costs, whether those costs are related to environmental policy or to other issues.

Auctions also have the beneficial attribute that they generate revenue that could be used to achieve other policy goals.[9] However, this benefit hinges on the wise handling of revenue from the auction. As noted previously, revenues generated by an auction can be used to compensate consumers for higher energy prices by reducing existing taxes; for reasons discussed in Issue Brief #6, this is the approach favored by most economists because the efficiency-enhancing effect of reducing taxes on investment or income helps to minimize total net costs to society. Other policy goals could include promoting R&D investments to advance renewables and other new technologies and compensating stakeholders that are adversely affected by the policy (such as mining communities) or by a changing climate. Indeed, funds could be directed to reduce the impact of climate change through adaptation. Alternatively, free allowances could be allocated to consumers, either directly or through an intermediary organization, or to states (presumably based on population, generation, or emissions)—in that case, free allowances would have to be converted to cash by selling them to regulated entities. In the northeastern states' RGGI memorandum of understanding, member states agreed to auction a minimum of 25 percent of the allowances created by the RGGI program and use the money to provide consumer benefits and for strategic energy purposes. Modeling has shown that the energy-efficiency investments funded by these allowance sales can reduce demand sufficiently to largely mitigate the electricity price increases that would otherwise occur in wholesale power markets. Many RGGI states have decided to auction fully 100 percent of their share of regional CO_2 emissions allowances under the RGGI cap, and many of these states envision using much of the resulting revenue to promote energy efficiency programs.

Although there are compelling arguments for auctioning all or most allowances under a cap-and-trade program, however,

8 These topics are extensively discussed in Issue Brief #6, which deals with allocation more generally.

9 The advantages of auctions are discussed in both Issue Brief #6, on allocation, and Issue Brief #5 on trading versus taxes.

several prominent proposals currently under consideration at the federal level provide for a substantial free allocation—at least in the early years of program implementation. The case for some free allocation is usually made on two grounds. First, policymakers may wish to shield consumers from price impacts related to the program (at least in areas that are still under cost-of-service regulation); although it is worth noting that this would also tend to diminish the efficiency of the policy by reducing incentives for customer-side demand reductions. The second motivation for a free allocation would be to compensate the shareholders of electricity-generation companies that are adversely affected by the policy. Research has shown, however, that accomplishing this latter objective should require only a portion of the total allowances needed to cover electricity sector CO_2 emissions.[10] Put another way, allocating 100 percent of allowances used by the electricity sector for free to generators would vastly over-compensate electricity suppliers in competitive regions, while benefiting electricity consumers in regulated regions.

In fact, many companies in competitive regions stand to profit from a mandatory climate policy even if 100 percent of allowances are sold at auction. These firms benefit because electricity prices in competitive markets—which are virtually always set by the marginal cost of generation from a fossil-fired facility—will rise to reflect the cost of emissions allowances. Higher prices will apply equally to all electricity sold, regardless of how it was generated. Given that many firms also own non-emitting or low-emitting generators, the revenue gains they experience as a result of higher prices are likely to outweigh whatever allowance costs they incur as a result of the policy. For reasons noted previously, such over-compensation is not expected to occur in traditionally regulated electricity markets. In these markets, regulators typically set electricity rates to recover the original cost of utility expenses. Therefore, to the extent that any new allowance costs are covered by an allocation of free allowances, utility expenses would not increase and electricity prices (and utility revenues) would not be expected to rise.

If policymakers decide to allocate emissions allowances for free based on the desire to compensate firms, they can adopt rules to achieve this goal at a lower cost (in the sense that fewer allowances must be given away to achieve a compensation goal) than simple grandfathering based on historic emissions. For example, free allocation could be based on particular firm-level metrics such as fuel mix or emission rates that provide some indication of a firm's likely exposure to adverse cost impacts under GHG constraints. The cost of compensating adversely affected firms (along with the potential for conferring additional windfalls on other firms that stand to gain under the policy) might be lowered further if allowances are initially apportioned to states and then states adopt a specific formula for distributing allowances to emissions sources.[11]

Another possible approach to free allocation involves updating an individual firm's share of free allowances based on a metric, such as share of total generation, which changes over time. Under this approach a firm that increases its share of total output can increase the share of free allowances to which it is entitled in the future. This has the desirable property that new entrants eventually receive allowances and retired emitters eventually do not. An updating approach is more feasible in the electricity sector than in other sectors because electricity production is a homogeneous good and easily measured. It also has the political virtue of mitigating the electricity-price increases that would otherwise be associated with a cap-and-trade policy in both regulated and deregulated regions (in contrast to other forms of free allocation that only limit the price increase in regulated regions).[12] Unfortunately, shielding consumers from price increases also weakens incentives for end-use efficiency improvements, thereby raising the overall cost of the policy to the economy (where that cost includes lost profit to generators and losses in consumer well-being). On the other hand, an updating, output-based allocation can amplify the incentive for generators to shift to lower-emitting technologies by driving up the price of emissions allowances (even as it has the opposite effect on electricity prices). Allowance prices can be expected to rise because an updating, output-based free allocation will tend to drive up the quantity of electricity generated (both by creating incentives for increased output and diminishing incentives for customer-side efficiency improvements). Increased output would likely translate to increased demand for allowances and upward pressure on allowance prices.

As mentioned above, the reason relatively few allowances would be required to compensate the electricity industry as a whole is that the vast majority of costs associated with emissions reductions in this sector would be borne by electricity consumers. Free allocation to generators

10 Modeling indicates that consumers bear eight times the cost that is born by shareholders under a cap-and-trade policy in the electricity sector. Burtraw, Dallas and Karen Palmer, 2007. Compensation Rules for Climate Policy in the Electricity Sector. Resources for the Future Discussion Paper 07-41. Washington, DC: RFF

11 Ibid.

12 This is because an output-based updating free allocation effectively creates a production subsidy: firms have an incentive to increase their output to capture a larger share of valuable free allowances in the future. This subsidy effect tends to drive prices lower as firms seek to sell more electricity. For a more thorough explanation of the incentive and price effects of different approaches to allocation, see Issue Brief #6.

The reason relatively few allowances would be required to compensate the electricity industry as a whole is that the vast majority of costs associated with emissions reductions in this sector would be borne by electricity consumers. Free allocation to generators compensates consumers in regulated regions of the country but benefits generators in competitive regions of the country.

compensates consumers in regulated regions of the country but benefits generators in competitive regions of the country, and hence accentuates regional differences in the incidence of cost under a mandatory climate policy. One proposal for addressing otherwise disparate price impacts across regulated versus competitive markets is to allocate emission allowances (or the value of emission allowances) to load serving entities (LSEs) based on one or more of a variety of measures including electricity consumption, population, or emissions by generators in a state. This approach is sometimes called "allocation to load." Free allowances allocated to an LSE would reduce the company's revenue requirements. This would offset the impact of the carbon policy on wholesale electricity prices and thereby mitigate the increase in retail electricity prices. As with an updating free allocation to generators, however, shielding consumers from price increases has the indirect effect of raising the overall cost of the program because it undermines incentives for low-cost end-use demand reductions. Furthermore, allocation to LSEs invites the question of how allowances should be distributed to these entities—e.g., on the basis of customers served, electricity delivered, or GHG emissions. Different allocation metrics imply a different regional distribution of costs under the program.

If the goal instead is to phase in higher retail prices so that consumers are increasingly exposed to the CO_2 price signal over time, it may be advantageous to assign allowance value to load (using revenues presumably captured through a separate auction of allowances) rather than allowances per se. This is because direct allocation of free allowances can create a sense of entitlement among recipient firms that would not accompany the distribution of equivalent revenues from an allowance auction. More generally, the merits of using allowance value to compensate private interests must be weighed against the other public purposes to which this value could be applied—among them providing broad-based tax relief. Distributing auction revenues rather than allowances per se places compensation goals and other stakeholder claims for a share of the allocation pie on more level footing with these other potential uses.

Beside the possibility of over-compensating some producers in competitive markets, experience with the European Union's Emission Trading Scheme suggests that free allocation has other problems. For example, free allocation can invite arbitrary provisions such as set-asides for new sources, adjustments for facility retirements, and benchmarking (where eligibility for free allocation might be tied to a requirement that a facility achieves the same emission rate as the most efficient new facility in a given class of technology). A significant body of literature indicates that these types of rules generate incentives that can raise the cost of the overall program and produce unintended consequences. Such provisions will complicate the cap-and-trade program in ways that seriously erode its transparency and efficiency and lead to unanticipated wealth transfers. These problems are generally more significant for updating free allocations than they are for free allocations that are decided on a one-time basis and are not adjusted over time in response to the entry of new facilities or the closure of existing ones.